National Energy Board

Office national de l'énergie

Short-term Canadian **Natural Gas** Deliverability

2005 - 2007

An **ENERGY MARKET ASSESSMENT** • October 2005

Canada

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Cat. No. NE2-1/2005E
ISBN 0-662-41791-7

This report is published separately in both official languages.

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For pick-up at the NEB office:
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Printed in Canada

N° de cat. NE2-1/2005F
ISBN 0-662-70347-2

Ce rapport est publié séparément dans les deux langues officielles.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
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Imprimé au Canada

FIGURES

TABLES

B.C.	British Columbia
CBM	coal bed methane
EMA	Energy Market Assessment
EUB	Alberta Energy and Utilities Board
LNG	liquefied natural gas
MAC	Multi-Stakeholder Advisory Committee
NEB or Board	National Energy Board
NGC	natural gas from coal
NGLs	natural gas liquids
N.W.T.	Northwest Territories
SOEP	Sable Offshore Energy Project
U.S.	United States
WCSB	Western Canada Sedimentary Basin

Units

m^3	= cubic metres
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Bcf	= billion cubic feet
m^3/d	= cubic metres per day
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day

Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C)	= 35.3 MMcf (@ 14.73 psia and 60° F)

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas.

The NEB collects and analyses information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board produces publications, statistical reports and speeches that address various market aspects of Canada's energy commodities. The Energy Market Assessment (EMA) reports published by the Board provide analyses of the major energy commodities. Through these EMAs, Canadians are informed about the outlook for energy supplies in order to develop an understanding of the issues underlying energy-related decisions. In addition, policy makers are informed of the regulatory and related energy issues that need to be addressed. On this note, the Board has received feedback from a wide range of market participants across the country that the NEB has an important role and is in a unique position to provide objective, unbiased information to federal and provincial policy makers.

This EMA report, titled *Short-term Canadian Natural Gas Deliverability, 2005–2007*, examines the factors that affect gas supply in the short term and presents an outlook for deliverability through to the year 2007. The main objective of this report is to advance the understanding of the short-term gas supply situation by examining recent trends in the production characteristics of the Western Canada Sedimentary Basin (WCSB) and the east coast offshore and applying these trends to provide an outlook for short-term Canadian deliverability. This report is also an update to the Board's November 2004 EMA, titled *Short-term Canadian Natural Gas Deliverability, 2004–2006*.

While preparing this report, the NEB conducted a series of informal meetings and discussions with drilling companies, pipeline companies, natural gas producers and industry associations. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

Questions and comments regarding this EMA can be referred to either:

Ken Martin — telephone: (403) 299-3107, email: kmartin@neb-one.gc.ca, or
Paul Mortensen — telephone: (403) 299-2712, email: pmortensen@neb-one.gc.ca

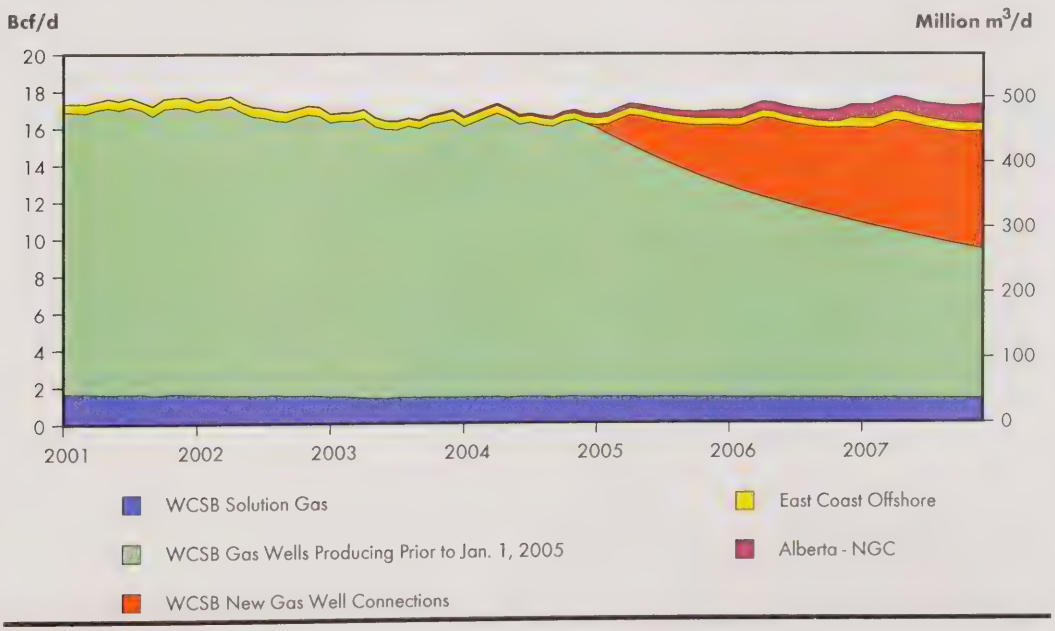
Overview

North American natural gas prices have escalated sharply since the start of 2004. The rise in gas prices has been influenced by a significant increase in world crude oil prices and a tight balance between natural gas supply and demand. The recent disruption of some United States (U.S.) gas supply because of hurricane activity along the Gulf of Mexico has exacerbated this market tightness and further increased prices. The integrated nature of the North American natural gas market means that price impacts in the U.S. ripple into Canada. Increasing natural gas prices could lead to economic challenges for some Canadian consumers and industries. At the same time, rising natural gas prices provide an incentive to develop additional natural gas supplies. This report provides an assessment of the expected capability of Canadian gas production, or deliverability, through 2007.

The increase in natural gas prices has led to record levels of drilling in Canada's natural gas exploration and production industry. The Board anticipates the industry will continue to maximize its efforts to increase production and expects the level of drilling to remain at very high levels. However, due to the maturity of the basin, this effort will result in only a modest increase in production over the next two years.

The Board expects average annual Canadian gas deliverability to rise from 478 million m^3/d (16.9 Bcf/d) in 2004 to 481 million m^3/d (17.0 Bcf/d) in 2005 and to 491 million m^3/d (17.3 Bcf/d) by 2007 (Figure 1).

Outlook for Canadian Gas Deliverability



Almost 98 percent of Canadian gas is produced from the Western Canada Sedimentary Basin (WCSB) with Alberta accounting for roughly 80 percent of the output. British Columbia and Saskatchewan contribute roughly 16 and 4 percent respectively of the total from the WCSB. Despite the projected high levels of drilling, the Board expects that production of conventional natural gas from the WCSB will decrease slightly from 462 million m^3/d (16.3 Bcf/d) in 2004 to 453 million m^3/d (16.0 Bcf/d) in 2007.

While production of conventional gas in the WCSB is expected to decline slightly, natural gas from coal (NGC)[1] in the WCSB is now an important and rapidly growing source of gas production. **Deliverability of NGC is expected to grow rapidly from 8 million m^3/d (0.3 Bcf/d) in 2005 to 25 million m^3/d (0.9 Bcf/d) in 2007.** Thus, the increase in production of NGC is expected to offset the declines in conventional gas production and enable a small overall increase in gas deliverability.

Since the start of the decade, gas production from Nova Scotia's Sable Offshore Energy Project (SOEP) has established a vital regional presence, serving domestic gas consumption in the Maritimes and export markets in the U.S. northeast. Deliverability of natural gas from SOEP is expected to remain at approximately 10 to 11 million m^3/d (0.4 Bcf/d) for 2005 and 2006 and to then briefly return to near its original production peak at 13 million m^3/d (0.5 Bcf/d) in 2007 with the installation of compression facilities.

Despite the contributions from Nova Scotia and NGC, production of conventional natural gas from the WCSB will remain the mainstay of Canadian gas production for many years. However, the WCSB is a well-explored basin and, on a basin-wide average, production is declining at about 20% per year from existing wells. Therefore, new gas wells have been, and continue to be, essential for maintaining Canadian gas deliverability at the stable levels seen over the past several years. There is an ongoing trend of year-on-year decreases in initial productivity from new gas wells in the WCSB. This means that drilling must increase every year to obtain the levels of deliverability from new wells needed to offset the decline in deliverability from existing wells. Drilling activity directed toward conventional gas resources in the WCSB in 2007 is expected to be 13 percent higher, in terms of drill days, than what occurred in 2004. This drilling effort is expected to result in gas-intent wells totalling 16 300 in 2005, increasing to 16 850 in 2007.

In addition to total drilling directed towards conventional gas resources, drilling effort directed toward NGC is projected to continue to increase markedly over the projection period, with the drilling effort in 2007 expected to be triple the 2004 level in terms of drill days. This rapid pace of NGC development is expected to result in approximately 3 400 NGC–intent wells drilled in 2005, increasing to 5 400 in 2007. This will result in sharply increasing NGC deliverability over the projection period.

Canadian natural gas prices are expected to remain at levels that ensure sufficient cash flow to fund the anticipated activity levels. The ability to reinvest these revenues productively to increase Canadian gas deliverability is constrained by several factors. These factors include the size and productivity of the Canadian drilling rig fleet, the availability of staff to operate the rigs and develop the projects, and the time and effort involved in developing an understanding of new resource types. **The Board is of the view that the size, capability and productivity of the Canadian drilling rig fleet is the key factor in determining the outlook for gas well completions and total gas production over the projection period.**

1 Also known as coal bed methane or CBM.

INTRODUCTION

Canada is an important source of natural gas supply in North America accounting for almost one-quarter of the combined production of Canada and the U.S. in 2004. Because of Canada's substantial role in North American natural gas supply, there is considerable interest in the outlook for Canadian gas production over the next few years. The primary objective of this report is to provide the Board's current outlook for Canadian natural gas deliverability to the end of 2007.

During the period covered by this report, Canadian gas production will be sourced from the WCSB and offshore Nova Scotia. This report examines deliverability from these two regions. As NGC in the WCSB is currently undergoing rapid development and is fast becoming a very important component of deliverability, this report provides a separate analysis of NGC deliverability. This assessment also entails a detailed examination of the Canadian rig fleet for the purpose of estimating future drilling levels on the basis of drilling capacity.

Chapter 2 provides background on Canadian supply and discusses current and emerging issues. Included is a description of the geographic extent and nature of the supply in each region. Also included is a discussion of recent regional production trends.

Chapter 3 describes the approach used to estimate Canadian gas deliverability. The productive life of each gas well is characterized by production decline, which is the initial production rate that declines as the resources of the well are depleted. The approach includes the analysis of production decline trends by study area to estimate future deliverability from existing wells. The chapter also describes how the production characteristics of the more recently connected wells are used to estimate initial productivity and decline rates for future gas well connections (a well completion with gas and/or oil production is defined as a connection). Also included in this chapter is an analysis of drilling capacity in the WCSB that is the basis for projecting the number of future gas connections.

Chapter 4 provides the results of the regional deliverability analyses including the estimated production characteristics for currently producing and future gas wells and the number of gas well connections expected over the projection period.

The Board's outlook for Canadian natural gas deliverability is presented in Chapter 5. The observations and issues of the assessment are discussed in Chapter 6.

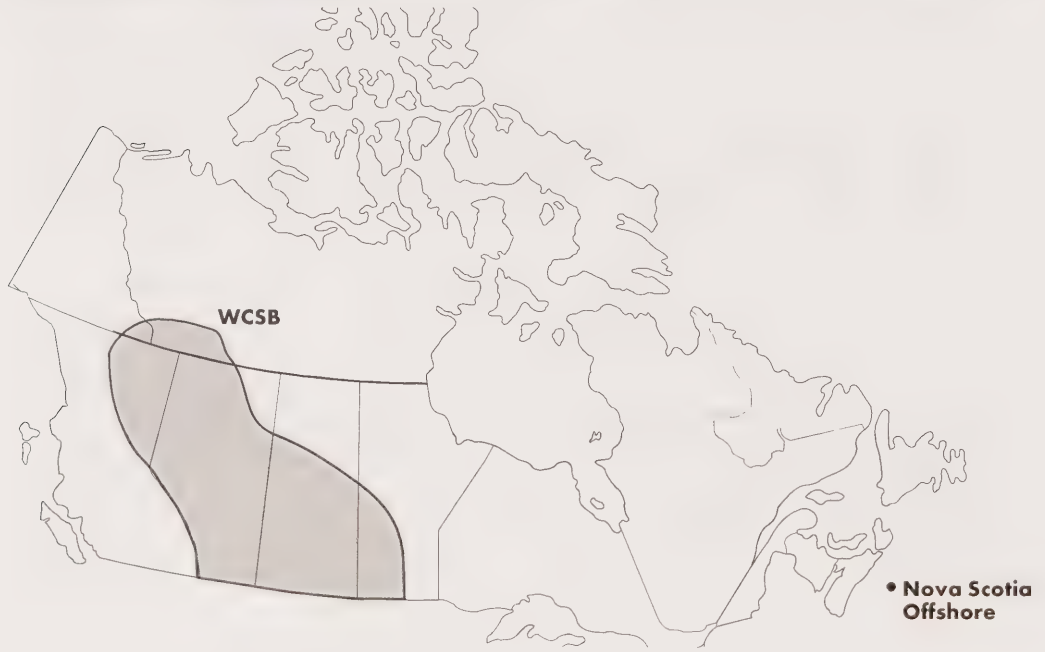
BACKGROUND

The WCSB has traditionally been Canada's main source of gas production and currently accounts for 98 percent of total Canadian production. Natural gas production from offshore Nova Scotia started at the end of 1999 and provides most of the remaining gas production in Canada[2]. Figure 2.1 shows the location of these gas producing areas. Descriptions of the significant features of the regions, a summary of recent production and description of current and emerging issues follow.

2.1 WCSB – Conventional Gas Supply

The WCSB underlies most of Alberta, significant portions of British Columbia (B.C.) and Saskatchewan, as well as parts of Manitoba and the Yukon and Northwest Territories (Figure 2.1). Alberta accounts for the largest share of production at roughly 80 percent. British Columbia and Saskatchewan provide roughly 16 and 4 percent of the total respectively. The Yukon and Northwest Territories currently contribute less than 1 percent of WCSB production and there is currently no gas production in Manitoba.

Canadian Gas Producing Areas



2 Minor amounts of gas production occur in other parts of the country including southern Ontario and New Brunswick. These minor production volumes will not be addressed in this assessment.

The large regional differences in physical and producing characteristics in the WCSB require that the basin be divided into smaller areas with similar characteristics for production decline analysis. For this assessment, the WCSB has been split into 14 geographic regions (the "study areas") based on similar producing characteristics, as shown in Figure 2.2.

WCSB historical gas production by connection year is shown in Figure 2.3. Conventional gas production from the WCSB has been stable for the past two years at around 460 million m^3/d (16.3 Bcf/d) as high levels of drilling activity have been offset by lower initial productivity of new wells and, in some cases, higher decline rates. The vital role of new drilling is also evident, with roughly 50 percent of current production provided by wells that have been on production for five years or less. The high level of drilling activity has been encouraged by rising prices that support the economics of low productivity wells.

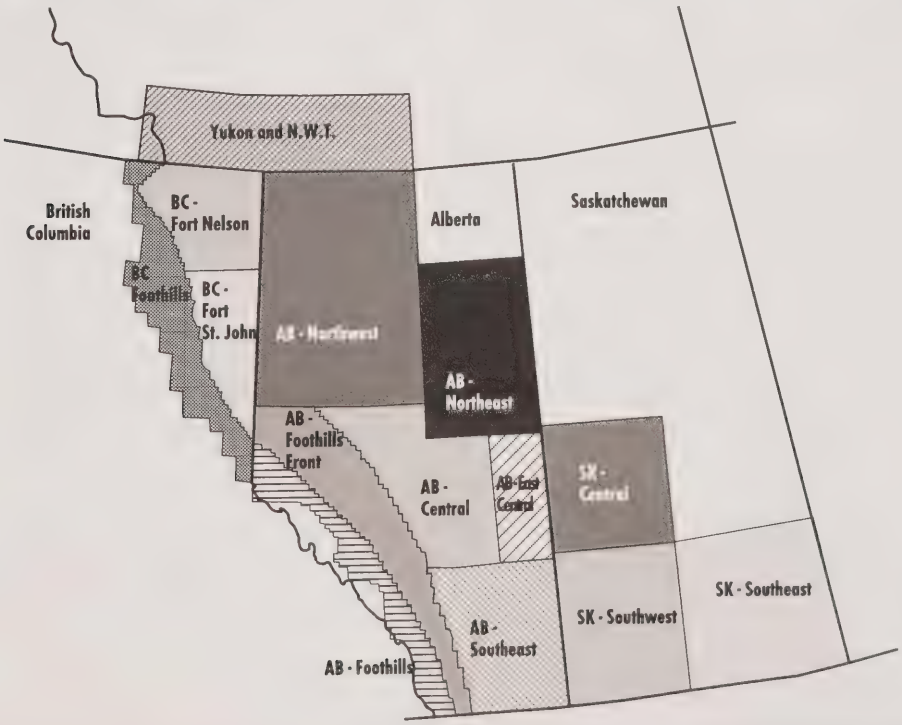
Higher prices also support the economics of some new resource types, such as NGC (described in a later section) and lower permeability, or "tighter" gas resources. Tighter gas resources continue to be recorded as conventional gas in this EMA due to their early stage of development and the lack of a clear distinction between the two categories.

2.2 WCSB – Natural Gas from Coal

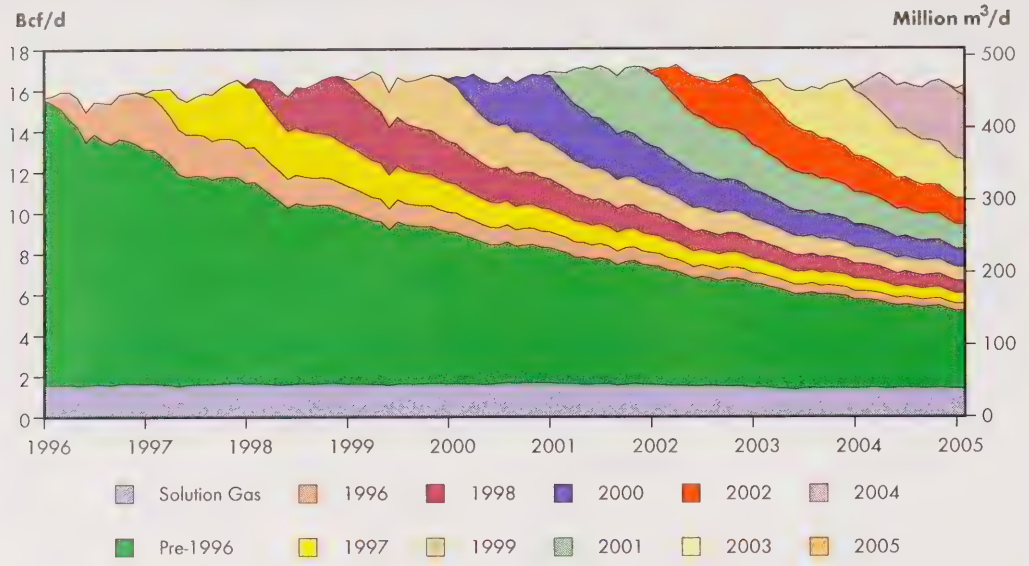
Natural gas from coal has emerged as a key new supply source in Canada. Coal deposits containing natural gas exist in many regions across the country, but development of the resource is in its infancy. Most of the NGC activity is in Alberta where the majority of the resource is located and where NGC development benefits from the availability of extensive existing infrastructure. Commercial NGC production is underway in some areas of Alberta, while still in the experimental stage in other parts of the province and in B.C.

FIGURE 2.2

Study areas in WCSB



WCSB Historical Conventional Gas Production by Connection Year



Source: GeoScout Well Production Records with Board Estimate of Shrinkage Applied

The two main geologic sources of NGC are the Horseshoe Canyon and Mannville coals. Appendix C.2 contains a map showing the approximate geographic extent of these two plays and location of NGC connections that existed as of the end of March 2005. Currently, production of NGC is almost entirely from Horseshoe Canyon coals in south central Alberta. Horseshoe Canyon coals have relatively low concentrations of natural gas but benefit from being fairly shallow, dry and more permeable than other coals.

The deeper Mannville coals represent a larger potential resource. The first commercial Mannville NGC project in Canada was announced in mid-2005. However, the variable nature of the Mannville resource means that economic feasibility has yet to be established beyond this initial project, and most Mannville development remains at the experimental stage.

Mannville coals have a higher concentration of natural gas, but will be more costly to develop because they are deeper and contain large quantities of saline water that must be produced and re-injected into deeper formations before gas production could begin. With water handling costs potentially being a key factor, consideration is being given to future royalty relief for water handling as a way to obtain greater contribution from this resource.

Figure 2.4 shows the dramatic growth in NGC production[3] that has occurred since the summer of 2003. During this time, NGC production increased from less than 1.4 million m^3/d (50 MMcf/d) to approximately 7 million m^3/d (250 MMcf/d). It should be noted that production from NGC wells might also include some volumes of conventional gas as the coals are often interbedded with conventional gas reservoirs.

With Horseshoe Canyon coals often consisting of multiple thin coal layers, development economics could potentially be enhanced by producing from the multiple seams simultaneously, referred to as commingling. For commingling to be viable, the practice must improve development economics and

3 In this EMA, NGC production is calculated as production associated with well IDs that are determined to be NGC as per the process described in Appendix C.1.

FIGURE 2.4

Alberta Historical NGC Production by Connection Year

Source: Well Production from GeoScout for Well IDs deemed as NGC by Board

deliverability without harming overall resource recoveries. Analyses of the impacts of commingling are currently underway and include industry testing and Alberta Energy and Utilities Board (EUB) analysis.

With the potential for developing NGC other than the dry Horseshoe Canyon coals, the consideration of practices and procedures to identify and continue to protect aquifers and water supplies is a key concern. The province of Alberta is currently moving toward developing recommendations in this area as part of its involvement with the CBM/NGC Multi-Stakeholder Advisory Committee (MAC)[4].

Alberta's MAC process is also considering developing practices and procedures to address noise concerns, assist with communication and notification of activities, promote landowner input, minimize wildlife disturbance, and protect environmentally sensitive areas.

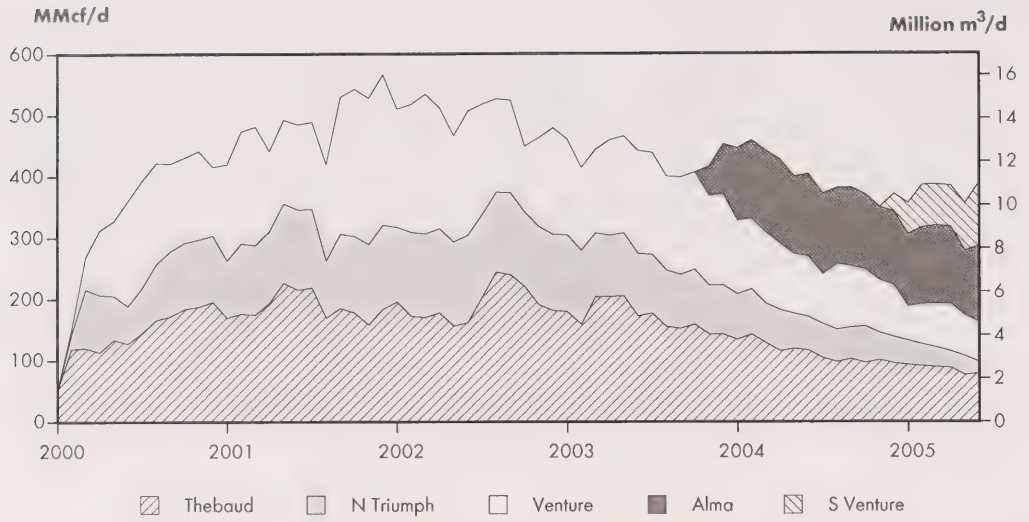
2.3 Nova Scotia Offshore

Since the start of the decade, gas production from offshore Nova Scotia has established a vital regional presence by providing energy consumers in the Maritimes with their first opportunity to use natural gas. As well, this supply source has provided significant exports to the U.S. northeast. Nova Scotia offshore production is delivered from the SOEP. The project started production at the end of 1999 and currently accounts for almost 11 million m^3/d (0.4 Bcf/d) or about 2 percent of Canada's natural gas deliverability.

The three original fields (Thebaud, North Triumph and Venture) of the SOEP have been experiencing natural production declines ranging from 33 to 50 percent since the start of 2004, as indicated in Figure 2.5. The connection of a fourth field, Alma, in late 2003 added 3.7 million m^3/d (0.13 Bcf/d) of production with little decline thus far. A fifth field, South Venture, was brought on stream in December 2004 and has offset continuing declines in production from the original three

4 *Coalbed Methane/Natural Gas in Coal Preliminary Findings*, July 2005. available at www.energy.gov.ab.ca/245.asp

Nova Scotia Offshore Gas Production



Source: Canada Nova Scotia Offshore Petroleum Board (with factor of 0.96 applied to convert from raw to marketable gas)

fields, keeping total Sable production in the range of 10 to 11 million m3/d (0.35 to 0.40 Bcf/d) over the first half of 2005.

The higher cost of offshore operations means that, when compared to onshore projects, offshore projects typically involve relatively few wells producing at fairly high rates. This tends to make deliverability more variable as aggregate production can be significantly affected by the performance of a few wells. Since the Maritimes region is reliant on a single offshore project, regional deliverability has also experienced significant variability. This is expected to remain a challenge for market participants as deliverability will continue to vary with natural field declines and added field compression over the period.

To this point, no decision has been made regarding the potential development of the Deep Panuke discovery. The decision might also await the completion of additional delineation drilling scheduled for 2006. With an expected three to four year lead time from decision to initial production, deliverability from any future Deep Panuke development would not occur in the time frame of this EMA. Access to transmission infrastructure might become a key consideration for the Deep Panuke project, should Liquefied Natural Gas (LNG) development in the region occupy existing and proposed pipeline capacity.

No gas-related exploration drilling is currently expected for offshore Nova Scotia in 2005. Some additional gas-related exploration drilling could potentially be undertaken in 2006 and 2007, but current industry interest is centred on oil development in the Orphan Basin off Newfoundland. While the existing Orphan Basin oil projects (Hibernia, Terra Nova, White Rose) contain significant volumes of associated gas, it is expected that this gas will continue to be used for pressure maintenance until at least the 2010 time frame.

2.4 LNG

Consideration of Canadian LNG regasification terminal projects is continuing. Two projects in the Maritimes have received regulatory approval and continue to work toward a point where they could make a firm commitment to proceed. Both projects are scheduling 2008 as the earliest year to begin operations.

In addition to the Maritimes, LNG projects are also under consideration in other parts of the country including Quebec and B.C.

METHODOLOGY

Canadian natural gas deliverability over the projection period will consist of conventional gas supply from the WCSB with contributions from offshore Nova Scotia and the rapidly growing NGC production from Alberta. In this EMA, trends in average production characteristics are used to determine conventional natural gas deliverability from the WCSB. The estimation of NGC deliverability is different because of the limited duration of NGC production history. To assess NGC performance, the Board consulted with industry to obtain views on possible production profiles in addition to analysis of the existing production data. A different approach is used for the Nova Scotia offshore where production history is obtained from a small number of wells from clearly defined fields. The estimate of Nova Scotia offshore gas deliverability focuses specifically on the SOEP, which is the source of almost all the gas production in the region.

3.1 WCSB – Conventional Gas Supply

The method used in this EMA to determine conventional gas deliverability from the WCSB can be summarized as follows:

Future Deliverability = [Future Deliverability from Existing Gas Connections] +
[Deliverability from Future Gas Connections] +
[Solution Gas Deliverability]

The above formula is applied to each of the study areas identified in Chapter 2 to obtain an estimate of short-term deliverability for the WCSB.

For the purpose of this report, "existing gas connections" means those wells brought on stream before January 1, 2005 and "future gas connections" means those brought on stream after January 1, 2005.

To estimate the **Future Deliverability from Existing Gas Connections** in each study area, gas connections were grouped by connection year and production decline analysis was performed to determine the parameters that define the future deliverability of the group.

To estimate the **Deliverability from Future Gas Connections**, production decline analysis was performed on production data for the "average gas connection" in each study area[5]. The analysis done on the average gas connections is very similar to that performed for existing gas connections, except that the focus is more on defining the production characteristics in the earlier stages of production, rather than emphasizing the most recent production history. The trends seen in the historic data were used to establish parameters that define the deliverability to be expected from future gas connections. The number of gas connections expected in future years is estimated and

5 In estimating the average gas well connection, the production history data is normalized by using the number of months since the start of production.

applied to the expected productivity of the typical gas connection of future years to obtain the Deliverability from Future Gas Connections.

Solution Gas Deliverability refers to natural gas produced in conjunction with oil production. Historical natural gas production data was totalled for all oil connections in each study area, and production decline analysis was performed to obtain the parameters that define Solution Gas Deliverability.

In this EMA each connection is categorized as either:

- a gas connection (conventional gas only);
- a NGC connection;
- an oil connection; or
- an oil sands connection.

Connections were categorized as either [gas/NGC] or [oil/oil sands] based on the connection's cumulative production. Other criteria were then used to further identify the NGC and oil sands connections to enable each connection to be classed as one of the four types listed above. Note that in this analysis gas connections are distinct from NGC connections.

The level of certainty and analysis effort associated with the different components of this deliverability projection can be summarized as follows:

Level of Certainty	Analysis Effort Required	Component of Deliverability
Higher ↓	Least ↑	Existing gas connections and solution gas
		Existing NGC connections
		Future gas connections
Lower	Most	Future NGC connections

The deliverability projection for existing gas connections and solution gas has the highest level of certainty while requiring the least amount of analysis effort in this assessment because the analysis extrapolates production history for existing wells. A lower degree of certainty is inherent in the deliverability projection for future gas connections because estimates of future drilling activity and performance of future gas connections are required. In view of the importance of future gas connections to deliverability over the projection period, more effort was expended in assessing parameters for future gas connections than what was required to assess existing gas connections.

The level of certainty for the deliverability projections for NGC (both existing NGC connections and future NGC connections) is less than the certainty for the corresponding conventional gas groupings. This is because there is a limited amount of gas production history available for NGC. However, the NGC production history that is available is sufficient to establish the initial productivity and first decline rate for the average NGC connection, and these are the key parameters to determine deliverability from future NGC connections over the projection period.

3.1.1 *Existing Conventional Gas Connections*

In each study area in Alberta, B.C. and Saskatchewan (except for the southeast area of Saskatchewan where only solution gas is produced) existing gas connections were grouped by connection year and a production decline analysis was performed on each grouping.

For each group of gas connections, the total marketable gas production for each calendar month was calculated and a plot of group production rate versus cumulative production was constructed to determine the following parameters:

- group deliverability as of December, 2004; and
- forward-looking exponential decline rate(s).

The above parameters can be applied to estimate future deliverability for each grouping of existing gas connections. Figure 3.1 shows the plot generated for the Alberta Foothills Front area for the 2000 connection year as an example of the method used to determine performance parameters for the group. The exponential decline rate is determined as the slope of the line formed by the production history data on the plot of production rate versus cumulative production. The decline rate determined in this manner is the nominal annual decline rate.

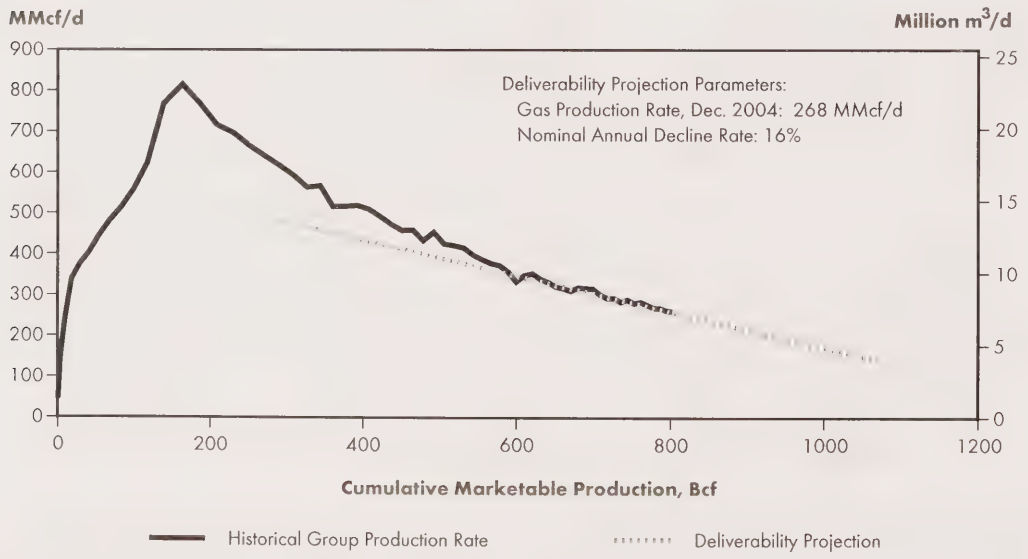
3.1.2 *Future Conventional Gas Connections*

Deliverability from future conventional gas connections is expected to form a large component of gas deliverability over the projection period. To estimate deliverability from this source, it is necessary to estimate the number of future gas connections and the average production characteristics of those future connections. This section describes the assessment of production performance characteristics of the average future gas connection and then describes the methodology used to determine the number of future gas connections.

3.1.2.1 Performance of Future Gas Connections

To assess the deliverability from future conventional gas connections in the WCSB, decline analysis was performed on production data representing the "average gas connection" in each study area.

Example of Group Production Decline Plot
(Alberta Foothills Front Area, 2000 Connection Year)



Source: Board Analysis of GeoScout Well Production Data

Production decline analysis suggests that the average gas connection in each study area tends to exhibit a steep decline during initial production, which usually lasts for about 17 months, followed by a period characterized by a significantly lower decline rate. To reflect this behaviour, the production decline analysis provides:

- initial production rate;
- first decline rate;
- months to second decline rate; and
- second decline rate.

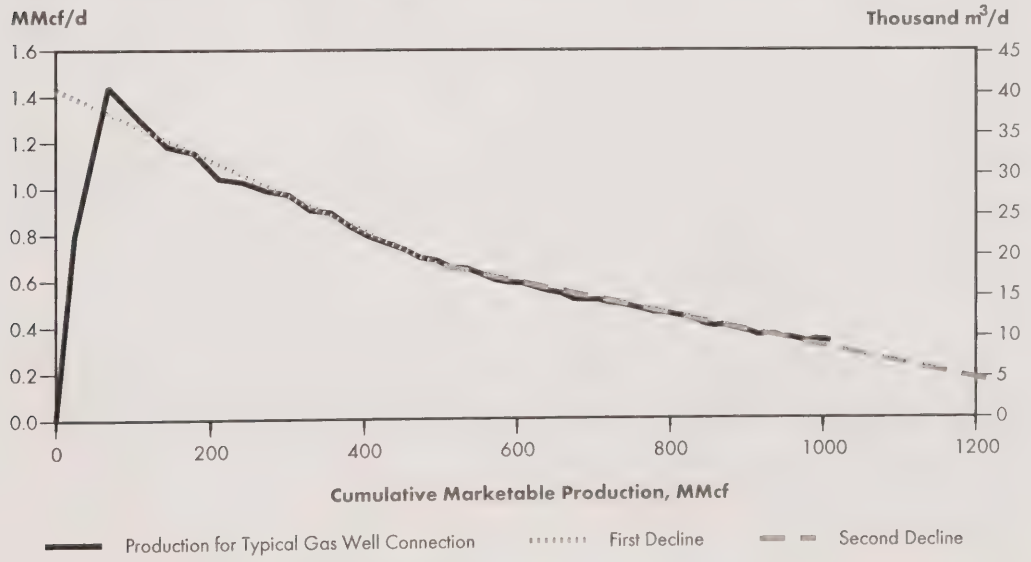
Figure 3.2 provides an example of the type of plot generated when conducting production decline analysis of the average gas connection. Plots of this nature were generated for all study areas and for all connection years between 1996 and 2004. Figure 3.2 shows the analysis for the Alberta Foothills Front area for gas connections brought on stream in 2000.

The production decline analysis (Figure 3.2) results in parameters that define the productivity of average gas connections in past years. The trends evident in well performance in the past years are identified to determine parameters that could be applied to future gas connections. In assessing the performance parameters of past years, it can be observed that generally the first decline rate, second decline rate and months to second decline rate were fairly constant in each study area, and thus it is reasonable to apply these historical parameters to future gas connections in each area. However, the initial productivity of the average gas connection generally decreases year after year. These trends are evidenced by examining the performance of the average gas connection over the entire WCSB in recent years (Figure 3.3).

Graphs showing the average gas connection performance for recent years and the projected gas well performance for each study area are contained in Appendix B.4.

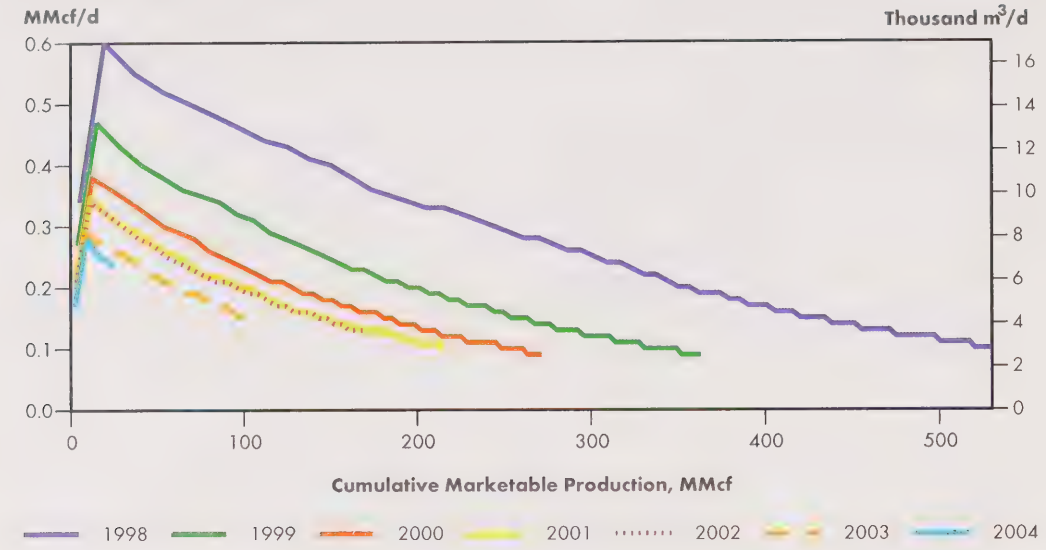
FIGURE 3.2

Example of Average Gas Connection Production Decline Plot (Alberta Foothills Front Area, 2000 Connection Year)



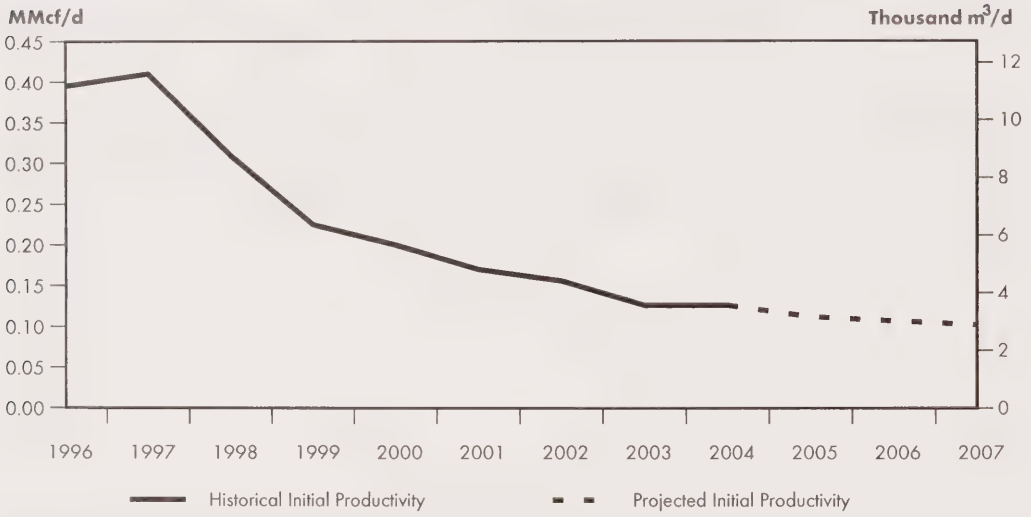
Source: Board Analysis of GeoScout Well Production Data

WCSB Average Gas Connection Performance



Source: Board Analysis of GeoScout Well Production Data

Example of Initial Productivity of Average Gas Connections by Connection Year (Area: Alberta – Southeast)



Source: Board Analysis of GeoScout Well Production Data

To determine the initial productivity of average gas connections in the future, the Board examined the trend in initial productivities over time in each area and projected values for future years that were consistent with the historical trend. Figure 3.4 illustrates the Board's method for selecting initial productivity of gas connections in 2005, 2006 and 2007.

3.1.2.2 Number of Future Gas Connections

The first step in determining the number of future gas connections is to estimate the level of gas well drilling that is expected to occur over the projection period. The number of future gas connections is estimated based on the projected number of gas-intent wells. In this EMA, the number of future gas-intent wells is calculated for each study area using the following equation:

[Average Number of Rigs in WCSB Rig Fleet for year (by rig category) * 365]
* [Study Area Rig Day Allocation Factors (for each rig category)]
* [Rig Utilization Factors (for each rig category and study area)]
* [Target Resource Fractions (for each rig category and study area)]
/ [Drill Days per Well (for each rig category, study area and target resource)]
=> Annual wells drilled (by rig category / study area / target resource)

The approach outlined above calculates the level of gas-intent drilling activity on the basis of drilling capacity, rig utilization and the fraction of drilling targeted to gas in the WCSB. In the market environment that is likely to prevail throughout the projection period, it is expected that drilling rigs in the WCSB will be used near the maximum level. Thus analysis of drilling capacity over the projection period should provide a reasonable estimate of gas-intent drilling over the projection period.

This EMA incorporates a detailed analysis of the Canadian rig fleet in the assessment of drilling capacity. The weekly *Rig Locator Report* published by Nickle's Energy Group (the *Rig Locator Report*) was used as the main source of data in this analysis.

The analysis began by identifying the part of the Canadian rig fleet that can be expected to be drilling in the gas producing areas of the WCSB. This portion of the Canadian rig fleet is referred to as the WCSB rig fleet in this EMA. Appendix A.1 shows the splitting of the Canadian rig fleet into five sub-fleets, which tend to work in specific geographic areas. The WCSB rig fleet comprises the vast majority (about 96%) of the Canadian rig fleet.

The WCSB rig fleet was split into three rig categories based on depth capacity of the drill rigs as follows:

Rig Category	**Depth Capacity (m)**
Shallow	Less than or equal to 1 850 m
Medium	Greater than 1 850 m and less than or equal to 3 050 m
Deep	Greater than 3 050 m

The number of rigs in each rig category of the WCSB rig fleet over the projection period was estimated based on information gathered from drilling industry organizations regarding new rig construction and the growth trends in each category over the past five years. Appendix A.2 details the historic and projected rig count for the WCSB rig fleet in each rig category.

With rig count projections for the three rig categories, the rigs were then allocated to the study areas in the WCSB. For each rig category, there are a total number of **rig days** available in each year of the projection period (i.e., the average number of rigs in the year multiplied by 365). The rig days for each rig category were allocated to each study area based on the historical rig location trends observed by the NEB. Some historical trends apply at a more aggregate level. For these particular trends, the historical rig days for each rig category in each study area were grouped into three main geographic areas– North, South and West. These three main geographic areas are defined as follows:

Main Geographic Area	Study Areas Comprising Main Geographic Area
North	AB-Northeast, AB-Northwest, BC-Fort St. John, and BC-Fort Nelson
South	AB-Central, AB-East Central, AB-Southeast, SK-Central, and SK-Southwest
West	AB-Foothills, AB-Foothills Front, and BC-Foothills

Trends by main geographic area can be observed in the charts contained in Appendix A.3.a. These geographic trends were combined with the trends applicable to individual study areas to provide the number of rig days in each year of the projection period for each rig category in each study area (see tables in Appendix A.3.b).

The historic data dealing with the utilization of rigs in each study area was investigated to provide a basis for estimating rig utilization for 2005–2007. Based on the *Rig Locator Report*, the number of rig days for each rig category in each study area for the past five years was determined. Analysis of well data from GeoScout provided the number of **drill days** associated with the rig categories in each study area. The rig utilization for years 2000 through 2004 was calculated for each rig category in each study area as drill days divided by rig days. Rig utilization levels for 2005–2007 (for each rig category and each study area) were then projected on the basis of the historical data. Appendix A.4 contains tables for each rig category and study area showing the historic and projected rig utilization factors. Application of the rig utilization levels to the corresponding rig day projections results in a projection of drill days for 2005–2007.

A further review of the historic drilling data derived from GeoScout provided insight into the specific resources that were the target of the drilling efforts over 2000–2004. Drilling in the WCSB is generally done for the purpose of exploiting one of the following resources (the "target resources"): conventional gas, NGC, conventional oil or oil sands. The drill days deemed by the NEB to be associated with each target resource were calculated for each rig category and each study area. Based on the historic allocation of drill days to target resources, and based on the Board's view of future exploitation levels of the target resources, allocation factors for each target resource were projected for each rig category in each study area (Appendix A.5). The Board's view of the exploitation levels of the target resources included insights obtained through industry consultations, particularly with respect to drilling targeted to NGC. Through the application of the target resource allocation factors, the number of drill days that might be expected for gas-intent drilling and NGC-intent drilling were calculated for each rig category in each study area. Note that with this assessment of drilling effort, a projection for NGC-intent drilling is produced at the same time as a projection for gas-intent drilling.

To determine the number of gas-intent wells and NGC-intent wells that can be expected over the projection period, the drill days per well were calculated. Drill days per well for 2000–2004 were calculated for each rig category in each study area for each resource target. The drill days for the past five years were used as the basis for projecting drill days per well for 2005 through 2007 (see Appendix A.6 to view details). Dividing drill days by drill days per well yields the number of wells to be drilled.

The gas-intent and NGC-intent drilling levels determined via this process are tabulated in terms of drill days and wells in Appendix A.7. It is useful to view the drilling levels in terms of drill days as this is the more meaningful measure when comparing the drilling efforts in the various study areas.

The ratio of number of gas connections and number of gas-intent wells drilled was investigated for the past five years for gas and NGC. The ratio for these years was used to project the ratio that was applied to the projection period. Appendix A.8 contains tables detailing the ratio of connections to wells for each study area for gas and NGC. Using the ratio of connections to wells and the number of wells expected to be drilled, the annual number of gas and NGC connections for the years 2005 through 2007 was calculated.

Finally, the fraction of annual connections that are expected to be made in each month of each year of the projection period are applied to the annual connections to obtain a monthly connection schedule for gas and NGC. Appendix A.9 shows the monthly connection fractions for each study area.

3.1.3 *Yukon and Northwest Territories*

In the Yukon and Northwest Territories, gas is produced from the Kotaneelee, Cameron Hills and the Liard Plateau gas fields (gas production from Ikhil and Norman Wells is not connected to the pipeline grid and so was not included in this assessment). Due to the small number of producing wells in the territories, a single production decline plot was generated for the aggregate production from Kotaneelee, Cameron Hills and the Liard Plateau to define future deliverability of the existing wells. The level of development anticipated for these producing fields over the projection period is not expected to significantly impact the deliverability from the area. Thus the performance parameters obtained from the production decline analysis were considered to be representative of the total deliverability for the area over the projection period.

3.1.4 *Solution Gas*

Solution gas currently accounts for about 8.5 percent of total marketable gas deliverability from the WCSB. To estimate future deliverability of solution gas, production decline analysis was performed to obtain the current production rate and the decline rate for solution gas in each study area in Alberta, B.C. and Saskatchewan (with the exception of B.C. Foothills which has no solution gas). As with the deliverability projection for existing gas connections, the deliverability projection for solution gas has a high level of certainty.

3.2 WCSB – Natural Gas from Coal (NGC)

To estimate deliverability from NGC wells, the same basic relationship is used as in assessing deliverability from conventional gas supplies (that is, future deliverability = deliverability from existing connections + deliverability from future connections).

3.2.1 *Existing NGC Connections*

Existing NGC connections in Alberta were grouped into those connections made before 2003, those made in 2003, and those made in 2004. For each of these groups, the total marketable gas production in each calendar month was calculated and a plot of group production rate versus cumulative production was made. From these plots, the deliverability as of December 2004 was determined for each group along with the forward-looking exponential decline rate(s). The expected performance characteristics of the average connection were considered when selecting the decline rate(s). The parameters for each group were used to project deliverability of existing NGC connections.

3.2.2 *Future NGC Connections*

As with the methodology used to assess deliverability for conventional gas supply, the assessment of deliverability from future NGC connections requires an estimate of the number of NGC connections and the production characteristics of the average NGC connection over the projection period.

To assess production characteristics of the average NGC connection, the performance of the average connection in years 2003 and 2004 were analyzed for the province of Alberta. Since approximately

90 percent of all existing NGC connections are associated with the 2003 and 2004 connection years, the average connection performance displayed in these two groupings provided a good basis for establishing performance parameters for the average NGC connection. Charts such as the one shown in Figure 3.2 were created for the average Alberta NGC connection for the 2003 and 2004 connection year groupings. This analysis enabled estimation of initial productivity and first decline rate of the average NGC connection. However, because of the limited duration of the majority of NGC production data, the second decline rate and the months to second decline could not readily be determined from this procedure. As a result, additional information on observed well performance provided by NGC producers was incorporated into the estimate of the second decline rate and months to second decline.

Unlike conventional gas connections, the initial productivity of the future average NGC connection was not projected to decrease from year to year over the projection period as this trend is not yet evident through the early stages of NGC development.

The drilling analysis described in Section 3.1.1.2 provided a projection of future drilling for NGC-intent wells as well as gas-intent wells for each year of the projection period. The annual number of NGC connections was calculated as a function of NGC-intent wells drilled in each year. The total number of NGC connections in Alberta and the performance parameters of the average NGC connection were used to obtain the deliverability projection for future NGC connections for 2005-2007.

3.3 Nova Scotia Offshore

For producing wells in the Nova Scotia offshore, an initial 24-month period of relatively constant production was followed by an annual exponential decline rate of 30 percent. This production profile was based on an average of the decline rates in the three original producing fields. A fifth producing field (South Venture) was brought into operation at the start of 2005. One new infill well was also recently drilled in the existing Venture field, with no additional wells planned for the producing fields at this time. Offshore compression is expected to be added at the end of 2006. The parameters used in the compression analysis were based on discussions with industry representatives.

DELIVERABILITY PARAMETERS – RESULTS

4.1 WCSB – Conventional Gas Supply

As discussed in Chapter 3, conventional gas supply in the WCSB is comprised of three components—Existing Gas Connections, Future Gas Connections and Solution Gas. The parameters relating to each of these components are discussed below.

4.1.1 *Decline in Production from Existing Gas Connections and Solution Gas*

Production decline analysis was performed for each study area and connection year for existing gas connections and for each study area for solution gas. As of the end of 2004, there were approximately 104 000 existing gas connections producing in the WCSB. From this analysis it was possible to determine the deliverability as of year-end 2004 and determine applicable production decline rate(s) from which future deliverability of existing gas connections and solution gas could be calculated. A table containing all production decline parameters for existing gas connections and solution gas is included as Appendix B.1. Deliverability can be projected from these parameters to be 462 million m^3/d (16.3 Bcf/d) at the end of 2004, 369 million m^3/d (13.0 Bcf/d) at the end of 2005, 310 million m^3/d (11.0 Bcf/d) at the end of 2006, and 266 million m^3/d (9.4 Bcf/d) by the end of 2007.

4.1.2 *Future Gas Connections*

The production decline analysis discussed in Section 4.1.1 concludes that, because of the historically consistent production decline in existing gas well connections and solution gas, approximately 93 million m^3/d (3.3 Bcf/d) of deliverability will have to be replaced annually from new gas wells to maintain production from the WCSB.

4.1.2.1 Performance Parameters for Future Average Gas Connections

The level of deliverability to be expected from future gas connections is a key factor in assessing future deliverability. The production decline analysis described in Chapter 3 provided the basis for establishing performance parameters for future gas connections.

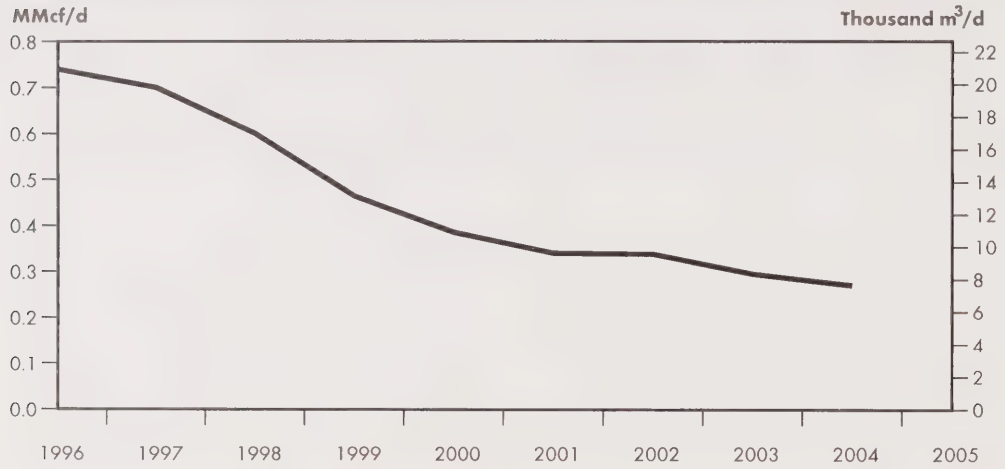
In general, the first and second decline rate and the number of months to the second decline rate observed in each geographic area have been fairly constant in recent connection years. Consequently, these average gas well performance parameters were applied to future connection years (see Appendix B.2). An exception to this trend is in the Fort St. John and Fort Nelson areas in northeast B.C., where significantly steeper initial decline rates were seen in 2003 compared to previous years. This is attributed to the large-scale development of tighter gas plays in those areas over the past two

years. Tighter gas resources are usually characterized by steep initial decline rates, followed by a progressive flattening out to very low rates of decline.

For the initial productivity of gas connections, the trend varies considerably from area to area (see Appendix B.3). In general, the initial productivity of gas connections continues to decrease from year to year, with smaller decreases apparent in recent years. Figure 4.1 shows the overall trend in initial gas well productivity over time for the entire WCSB.

Specific performance parameters established for future gas connections in each study area for 2005–2007 are shown in Table 4.1.

WCSB Initial Productivity of Average Gas Well Connections by Connection Year



Source: Board Analysis of GeoScout Well Production Data

Production Characteristics for Average Gas Connections by Area in 2005, 2006 and 2007

Area	First Decline Rage (fraction)	months to 2nd decline	Second Decline Rate (fraction)	Initial Productivity					
				2005 Gas Connections		2006 Gas Connections		2007 Gas Connections	
				$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d
Alberta - Foothills	0.40	20	0.17	43.91	1.550	42.49	1.500	41.08	1.450
Alberta - Foothills Front	0.49	17	0.25	17.28	0.610	16.15	0.570	15.16	0.535
Alberta - Southeast	0.62	17	0.27	3.17	0.112	3.03	0.107	2.89	0.102
Alberta - East Central	0.62	20	0.28	3.97	0.140	3.54	0.125	3.40	0.120
Alberta - Central	0.64	18	0.34	7.65	0.270	7.08	0.250	6.52	0.230
Alberta - Northeast	0.31	24	0.21	5.24	0.185	4.82	0.170	4.53	0.160
Alberta - Northwest	0.55	20	0.33	11.90	0.420	11.05	0.390	10.48	0.370
B.C. - Fort St. John	0.75	16	0.25	22.10	0.780	21.53	0.760	20.96	0.740
B.C. - Fort Nelson	0.70	16	0.25	32.58	1.150	31.16	1.100	29.75	1.050
B.C. - Foothills	0.30	24	0.20	84.99	3.000	79.32	2.800	73.65	2.600
Saskatchewan - Central	0.60	18	0.28	6.01	0.212	5.92	0.209	5.84	0.206
Saskatchewan - Southwest	0.45	17	0.23	1.84	0.065	1.78	0.063	1.73	0.061

4.1.2.2 *Number of Future Gas Connections*

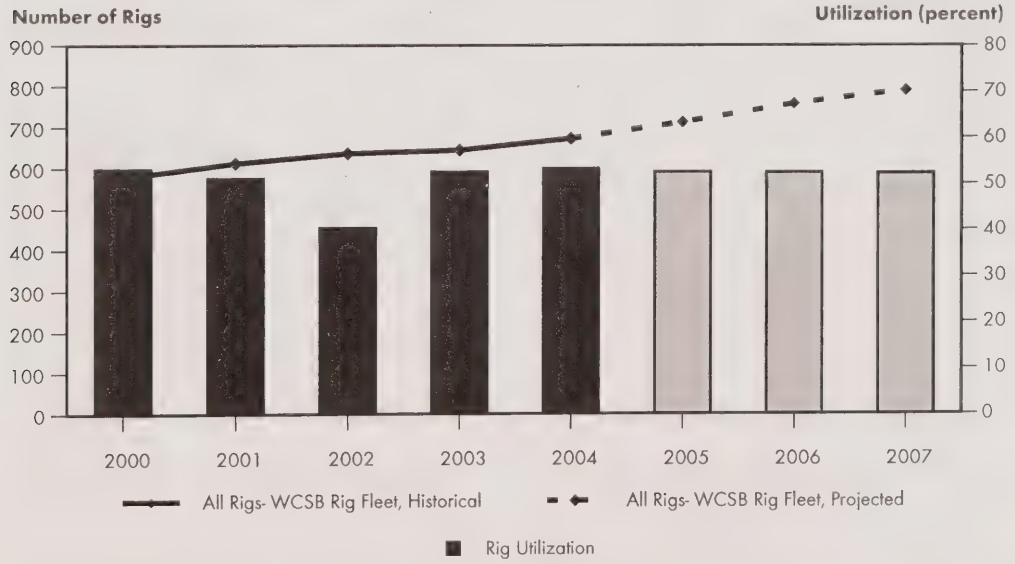
In this report, the number of future gas connections was determined as a function of gas-intent drilling. Gas-intent drilling was determined through the assessment of drilling capability in the WCSB. As discussed in Chapter 3, gas-intent drilling in the WCSB will be undertaken by that portion of Canadian rigs that comprise the WCSB rig fleet (Appendix A.1).

Strong natural gas prices are expected to drive growth in the WCSB rig fleet over the projection period. Based on historical trends and consultations with industry, the Board has made projections of WCSB rig fleet growth for each rig category – shallow, medium and deep (Appendix A.2). The allocation of the WCSB rig fleet to the various study areas and the rig utilization levels expected over the projection period are described in detail in Appendices A.3 and A.4 respectively.

The growth of the WCSB rig fleet (including all rig categories) and the projected overall rig utilization levels are shown in Figure 4.2. Note that the overall rig utilization calculated in this assessment has not exceeded approximately 53 percent in any of the past five years, in spite of these years being among the busiest drilling years in history. The NEB believes that overall rig utilization levels of 52–53 percent represent the operational maximum for the industry in the WCSB. Consultations with industry revealed that down time associated with spring break up, rig moving, contrary weather and rig servicing all serve to limit the overall rig utilization level. Thus, the overall rig utilization levels for the projection period shown in Figure 4.2 represent the drilling industry operating at close to maximum capacity.

The increasing size of the WCSB rig fleet and the consistently high rig utilization levels projected in this EMA result in a progressively higher number of drill days that can be expected in each year of the projection period. The allocation of these drill days to target resources for each rig category in each study area is described in Appendix A.5. Figure 4.3 summarizes this allocation of drill effort in terms of percentage of total drill days allocated to gas and NGC. The chart shows the increasing focus of the drill effort on gas relative to oil and the emergence of NGC as a significant drilling

WCSB Rig Fleet Growth and Utilization



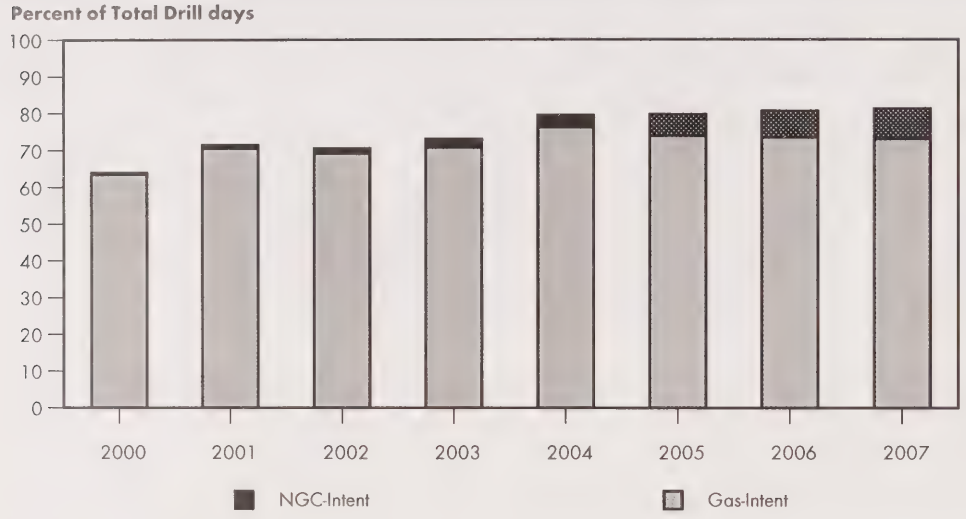
Source: NEB analysis of Nickle's *Rig Locator Report* and GeoScout Well Data

target over the past five years. Figure 4.3 also shows increasing levels of NGC-intent drilling and the continued large share of gas-intent drilling projected for 2005-2007.

Applying the drill days per gas well (see Appendix A.6) to the gas-intent drill days provides a projection of the number of gas-intent wells for each resource in each study area. Tables summarizing the gas-intent drilling effort both in terms of drill days and wells are contained in Appendix A.7. Figure 4.4 provides the historic and projected drilling effort of the WCSB rig fleet for gas and NGC in terms of both drill days and wells. The chart shows that approximately 16 300 gas-intent wells will

FIGURE 4.3

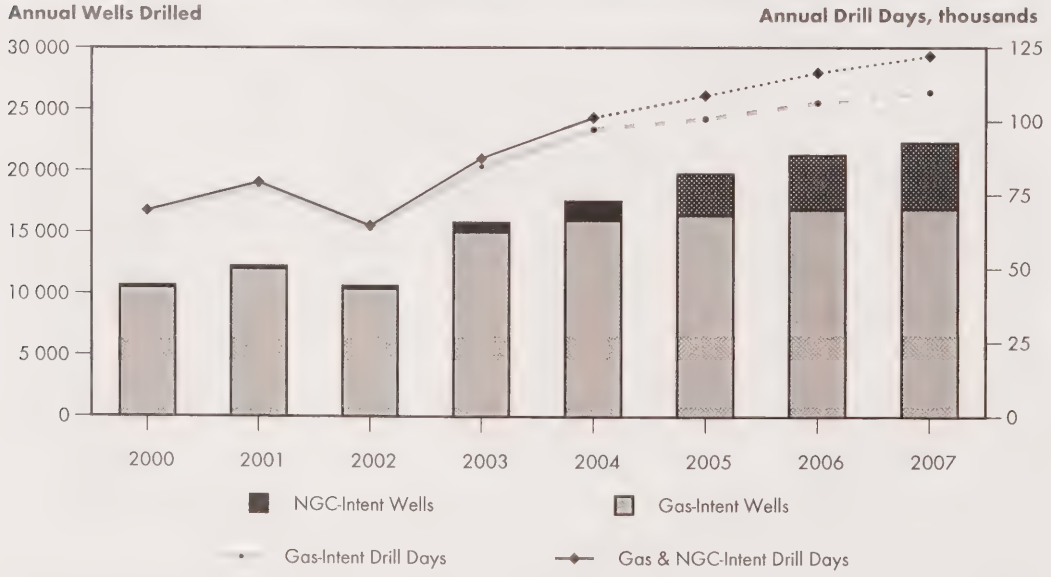
Portion of WCSB Rig Fleet Drill Days Directed to Gas and NGC



Source: : NEB analysis of GeoScout Well Data

FIGURE 4.4

WCSB Rig Fleet Annual Drill Days and Wells – Gas-Intent and NGC-Intent



Source: : NEB analysis of GeoScout Well Data

be drilled in the WCSB in 2005, and 16 800 gas-intent wells will be drilled in each of 2006 and 2007. A progressively larger share of gas-intent wells is projected to occur in the western side of the WCSB where the basin is much deeper and drill days per well much greater. This greater focus of drilling on the western side of the basin is the reason why the number of gas-intent wells does not increase in proportion with the increasing gas-intent drill days over the projection period.

The number of future gas-intent wells is converted into future gas connections by applying a factor based on the historical relationship between the two parameters. Appendix A.8 provides a summary of the historical and projected ratio of connections to wells in each geographic area for gas and NGC. Based on these factors, the Board's projection of gas and NGC connections by area is shown in Table 4.2. The Board projects that there will be 15 700 conventional gas connections in the WCSB in 2005 and approximately 16 000 in each of 2006 and 2007.

Steady increases are projected in the expected number of new conventional gas connections in the Foothills, Foothills Front and Central areas of Alberta, and in all three areas of Northeast BC. High usage of the medium and deep rigs that tend to operate in these areas and the relatively high level of prospectivity of conventional gas in these areas will drive the projected increase in the number of gas connections. The higher level of initial productivity of gas connections in these areas helps to maintain overall deliverability from the WCSB.

Annual gas connections are expected to remain approximately level or even decrease slightly in the East Central, Southeast, Northeast and Northwest areas of Alberta and in the Central and Southwest areas of Saskatchewan. Any reductions in future gas connections in these areas is largely attributable to competition from NGC drilling for the shallow and medium rigs that tend to work in these areas and because of lower prospectivity of conventional gas in these areas.

Projected Gas and NGC Connections by Area

Study Area	Projected New Gas and NGC Annual Connections		
	2005	2006	2007
Conventional Gas Connections			
Alberta - Foothills	94	105	115
Alberta - Foothills Front	1 956	2 117	2 217
Alberta - Southeast	6 814	6 865	6 676
Alberta - East Central	874	860	846
Alberta - Central	1 608	1 732	1 781
Alberta - Northeast	433	411	389
Alberta - Northwest	1 010	995	979
B.C. - Fort St. John	621	650	679
B.C. - Fort Nelson	336	349	362
B.C. - Foothills	32	35	38
Saskatchewan - Central	262	262	262
Saskatchewan - Southwest	1 683	1 693	1 683
Subtotal – Conventional Gas Connections	**15 725**	**16 063**	**16 026**
NGC Connections			
Alberta - NGC	3 148	4 185	5 202
Total – Conventional Gas plus NGC Connections	**18 873**	**20 248**	**21 228**

4.2 WCSB – Natural Gas from Coal

4.2.1 *Existing NGC Connections*

Natural gas from coal deliverability as of the end of 2004 was about 5.6 million m^3/d (0.20 Bcf/d). Based on the performance parameters estimated for existing NGC connections (see Appendix B.1), deliverability of these connections is expected to be 4.7 million m^3/d (0.17 Bcf/d) by the end of 2005, 4.1 million m^3/d (0.15 Bcf/d) by the end of 2006, and 3.6 million m^3/d (0.13 Bcf/d) by the end of 2007.

4.2.2 *Future NGC Connections*

The NEB's estimate of the number of future NGC connections was obtained by the same process used to determine the projected future conventional gas connections. To review the factors leading to the estimation of the number of NGC connections, see Appendices A.2 to A.8. NGC-intent wells (shown stacked on top of gas-intent wells in Figure 4.4) are expected to amount to approximately 3 400 wells in 2005, 4 500 in 2006, and 5 400 in 2007. The large increase in NGC-directed drilling primarily reflects the heavy development of the Horseshoe Canyon NGC play in the Calgary–Edmonton corridor (see Appendix C.2 for map). The number of NGC connections resulting from this drilling effort were projected to be approximately 3 100 in 2005, 4 200 in 2006 and 5 200 in 2007.

While the production history of NGC is of limited duration, Alberta had approximately 600 NGC connections in 2003 and 1 400 NGC connections in 2004, providing a sufficiently large data set upon which to base the assessment of initial productivity for the average NGC connection. Initial productivity of the average NGC connection of 2.8 thousand m^3/d (100 Mcf/d) is used in this assessment for the future NGC connections for all three years of the projection period, based on analysis of the 2003 and 2004 connection years. The Board projects a nominal annual decline rate of 25 percent for the average NGC connection based on the decline rates exhibited in NGC connections made in 2003. From industry consultations, the duration of the first decline period was set at 20 months with an annual decline rate of 12 percent applied in subsequent months.

4.3 Nova Scotia Offshore

Nova Scotia offshore deliverability was sourced from four fields in 2004. A fifth field (South Venture) commenced production at the start of 2005, with field development occurring over the first half of the year. Total deliverability at the end of 2004 was about 10.5 million m^3/d (0.37 Bcf/d).

The addition of offshore compression at SOEP at the end of 2006 is expected to boost deliverability by 20 percent in 2007.

DELIVERABILITY OUTLOOK

The outlook for Canadian gas deliverability is shown in Table 5.1 by study area. The table shows annual average production for 2004 and expected annual average deliverability for 2005, 2006 and 2007 for each component. Canadian annual average deliverability is expected to increase slightly from 477 million m^3/d (16.9 Bcf/d) in 2004 to 491 million m^3/d (17.3 Bcf/d) in 2007.

5.1 WCSB – Conventional Gas

The average annual deliverability of conventional gas from the WCSB is expected to decrease slightly over the projection period from 462 million m^3/d (16.3 Bcf/d) in 2004 to 453 million m^3/d (16.0 Bcf/d) in 2007. At the same time, deliverability of conventional gas from the largest producing province,

Canadian Gas Deliverability Outlook by Area

Area	Average Annual Production							
	Historical		Projection					
	2004		2005		2006		2007	
	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d	$10^3m^3/d$	MMcf/d
Alberta - Foothills	17.91	632	18.57	655	19.16	677	19.89	702
Alberta - Foothills Front	126.82	4 477	129.44	4 569	131.65	4 647	132.92	4 692
Alberta - Southeast	79.63	2 811	80.70	2 849	78.83	2 783	76.84	2 712
Alberta - East Central	17.86	630	17.42	615	16.61	586	15.84	559
Alberta - Central	45.51	1 606	45.09	1 592	44.48	1 570	43.61	1 540
Alberta - Northeast	27.59	974	24.34	859	22.02	777	19.89	702
Alberta - Northwest	52.76	1 863	50.83	1 794	47.98	1 694	45.27	1 598
B.C. - Fort St. John	37.09	1 309	36.65	1 294	37.02	1 307	37.44	1 322
B.C. - Fort Nelson	25.62	904	25.96	916	27.32	964	28.24	997
B.C. - Foothills	10.27	363	11.46	405	12.00	423	12.41	438
Saskatchewan - Central	5.16	182	5.91	209	5.99	212	6.05	214
Saskatchewan - Southwest	13.68	483	13.51	477	13.46	475	13.38	472
Saskatchewan - Southeast	0.84	30	0.85	30	0.84	30	0.83	29
Yukon and Northwest Territories	1.70	60	1.24	44	0.92	33	0.68	24
Total WCSB Conventional Gas	**462.46**	**16 325**	**461.96**	**16 307**	**458.29**	**16 178**	**453.30**	**16 002**
Alberta - NGC	3.75	132	8.47	299	15.84	559	24.59	868
Total WCSB - All Gas	**466.20**	**16 457**	**470.43**	**16 606**	**474.14**	**16 737**	**477.89**	**16 870**
East Coast Offshore	11.34	400	10.87	384	10.51	371	13.50	477
Total Canada	**477.54**	**16 857**	**481.30**	**16 990**	**484.65**	**17 108**	**491.39**	**17 346**

Alberta, is expected to decline over the projection period from approximately 368 million m^3/d (13.0 Bcf/d) in 2004 to 354 million m^3/d (12.5 Bcf/d) in 2007. Decreases in production are expected to occur in Alberta's Northeast and Northwest study areas, which in aggregate are expected to fall from an annual average of 80 million m^3/d (2.8 Bcf/d) in 2004 to 65 million m^3/d (2.3 Bcf/d) in 2007. While the Alberta Foothills area is expected to increase slightly, the large contribution from the Foothills Front, Southeast Alberta and Central Alberta is expected to be fairly stable for the projection period at an aggregate of approximately 250 to 255 million m^3/d (8.9 to 9.0 Bcf/d).

Deliverability is expected to increase in all three areas of B.C. over the projection period, resulting in total B.C. production increasing from an annual average of 73 million m^3/d (2.6 Bcf/d) in 2004 to an annual average of 78 million m^3/d (2.8 Bcf/d) in 2007. While the increase in drilling activity in Northeast B.C. is expected to be large, the high initial decline rate of new gas connections in the Fort St. John and Fort Nelson areas somewhat mutes the amount of deliverability resulting from this effort.

Total deliverability from Saskatchewan is projected to remain approximately stable over the projection period at 20 million m^3/d (0.7 Bcf/d).

5.2 WCSB – Natural Gas from Coal

NGC production in Alberta has grown remarkably over the past few years and is expected to play an even larger role in the Canadian gas supply over the projection period. NGC deliverability is expected to rise by a factor of more than six over the three-year period from an annual average of 3.8 million m^3/d (0.13 Bcf/d) in 2004 to 24.6 million m^3/d (0.87 Bcf/d) in 2007. Practically all of the production is expected to be from the Horseshoe Canyon coals of south central Alberta.

The projected increases in NGC deliverability require continuing growth in NGC drilling activity. Prior to 2005, about 2 300 NGC connections existed in western Canada. In 2005, NGC drilling activity is expected to result in 3 100 new NGC connections. NGC drilling activity is expected to continue to increase over the projection period, reaching 5 400 NGC-intent wells drilled in 2007 (see Figure 5.1). By 2007, NGC is expected to account for roughly 5 percent of overall Canadian deliverability.

5.3 Nova Scotia Offshore

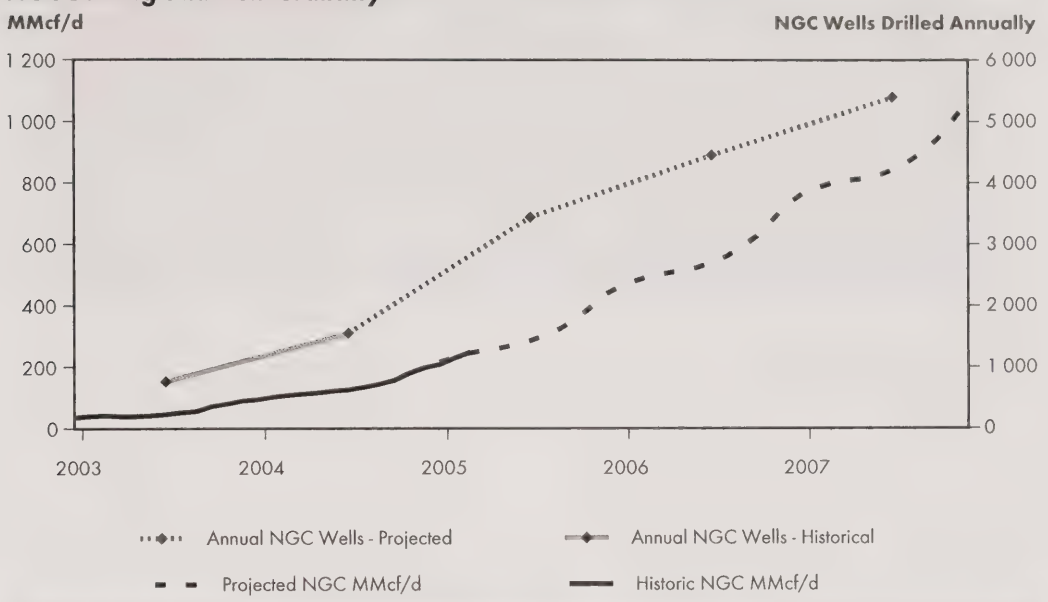
As illustrated in Figure 5.2, the estimate of deliverability from the SOEP through 2006 incorporates ongoing natural declines in the four producing fields and the addition of the South Venture field at the start of 2005. The contribution from South Venture is expected to help maintain production between 10 and 11 million m^3/d (0.35 to 0.40 Bcf/d) for most of the period to late-2006. The addition of offshore compression for the end of 2006 is expected to increase production from the original fields to average 13 million m^3/d (0.48 Bcf/d) in 2007. However, the variability in deliverability over the period will continue to present challenges to markets in the area.

5.4 Total Canada

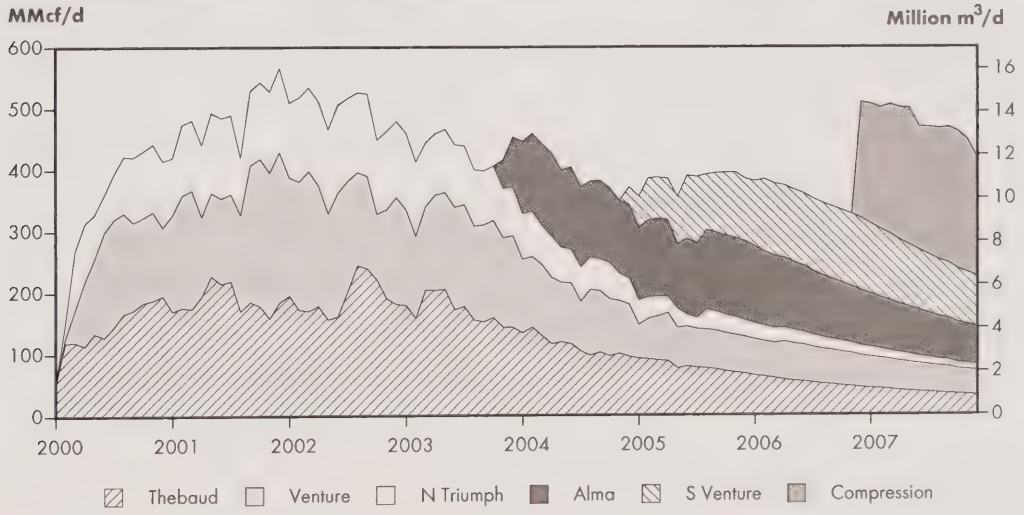
Figure 5.3 portrays the outlook for total Canadian gas deliverability and the major segments of gas supply over the projection period (Note: Figure 5.3 is also shown in the *Overview* section of this EMA). Total Canadian production is expected to increase slightly over the projection period. This increase is due to the increasingly significant production of NGC added on to the quite stable levels of conventional gas production expected in the WCSB. The annual bump in deliverability occurring

in the first few months of each year of the projection period is caused by the seasonal connection patterns that prevail in the WCSB. Production from the Nova Scotia offshore is somewhat variable, but is expected to average around current levels for most of the projection period.

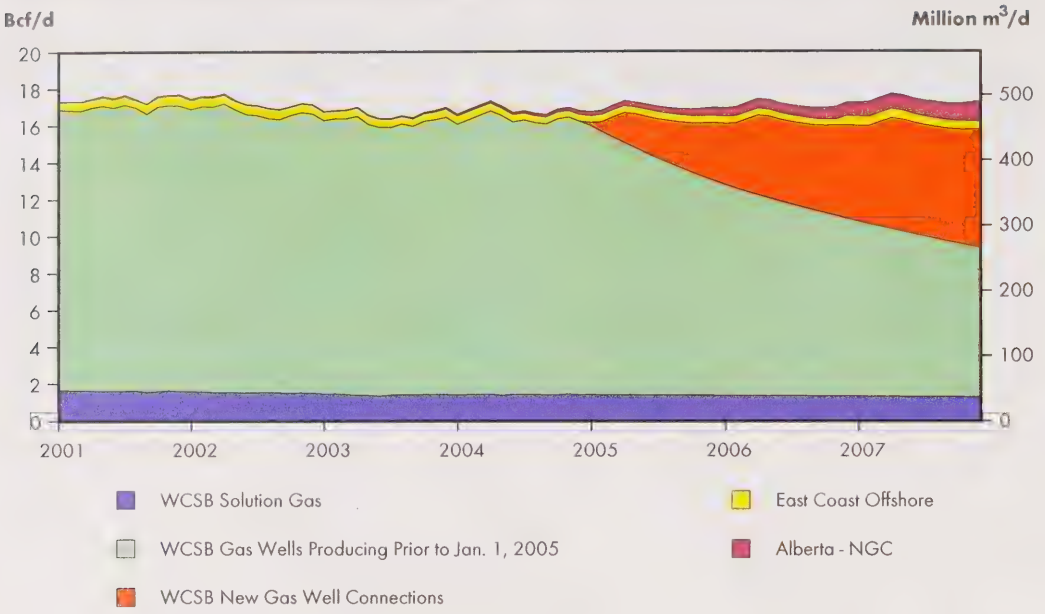
NGC Drilling and Deliverability



Nova Scotia Offshore Deliverability Outlook



Outlook for Canadian Gas Deliverability



Observations And Issues

6.1 Observations

High natural gas prices in the North American market are driving maximum utilization of the growing rig fleet. As a result, the drilling effort directed toward gas and NGC (in terms of drill days) is expected to increase by approximately 20 percent by 2007 in comparison with 2004 levels (Notes: this level of increase refers to the aggregate of gas and NGC drill effort).

The effective decline rate for production from existing wells is expected to remain at around 20 percent per year. This means that in each year new connections need to replace about a fifth of the previous year's output to keep overall production constant.

The trend of lower initial productivity in new WCSB gas wells is continuing. Consequently, to offset production declines from producing wells, the number of new gas connections must rise each year to maintain production levels. The Board expects that the number of gas-intent wells (for conventional resources) will increase from just under 16 000 in 2004 to approximately 16 800 by 2007, resulting in a 2 percent decrease in deliverability from conventional sources over the projection period.

The small drop in deliverability projected for conventional resources is expected to be more than offset by dramatic growth in deliverability from NGC. The Board expects that there will be approximately 3 400 NGC-intent wells drilled in 2005 rising to 5 400 in 2007. In comparison, NGC-intent wells in 2001 and 2002 averaged around 250 wells per year. As a result of this explosive growth in NGC drilling, deliverability from NGC is expected to increase from an average of 8.5 million m^3/d (0.30 Bcf/d) in 2005 to 24.6 million m^3/d (0.87 Bcf/d) in 2007.

The contribution from offshore Nova Scotia is expected to remain in the range of 10 to 11 million m^3/d (0.35 to 0.40 Bcf/d) until late 2006, and rise to average 13 million m^3/d (0.48 Bcf/d) in 2007 with added compression.

Canadian gas deliverability is projected to increase by about 3 percent, from an average 2004 deliverability of 478 million m^3/d (16.9 Bcf/d) to an average 2007 deliverability of 491 million m^3/d (17.3 Bcf/d).

Increasing drilling activity for conventional gas is occurring on the western side of the WCSB. The combination of high gas prices, improving technology and the ever increasing knowledge of the basin potential and resource exploitation practices, is resulting in the development of deeper and tighter conventional gas resources on the western side of the basin. While these tighter gas resources usually have steep initial decline rates, the subsequent progression to very low rates of decline over a very long productive life is expected to have a stabilizing effect on overall basin deliverability over the long term. The low decline characteristics of NGC wells are expected to have a similarly stabilizing effect on basin deliverability over the long term.

6.2 Issues

The Canadian upstream industry has a choice between reinvesting in gas deliverability and investing elsewhere (e.g., oil reinvestment, foreign investment, trust distributions, share buybacks). Experience to this point indicates that industry is reinvesting in Canadian gas deliverability at the maximum possible level, given the constraints on manpower, equipment and infrastructure.

Canadian deliverability levels are highly dependent on industry activity, particularly drilling. The prevailing environment of high gas prices enables full use of the rig fleet in Western Canada. Thus the capacity of that fleet is the limiting factor on drilling activity over the projection period. The likelihood of a curtailment of drilling is considered to be remote given the prevailing market conditions. However, if drilling were to be curtailed for any reason, the resulting fewer number of new gas wells would certainly cause a drop in overall Canadian deliverability from that projected in this report.

While strong gas prices are the primary driver for the increasing size of the Canadian rig fleet and the high use of that fleet, even greatly increased prices cannot drive deliverability significantly higher than what is projected in this report. As this EMA anticipates a high level of rig fleet growth and provides for use of the fleet at close to maximum capacity, there is little opportunity to further increase drilling and thereby deliverability from that projected in this report, regardless of the gas price.

The Canadian drilling industry faces an ongoing challenge of staffing the growing rig fleet. The future levels of drilling anticipated for the WCSB will require a well-trained and skilled workforce to conduct work in a safe and environmentally sound manner. The drilling industry's ability to maintain or even increase rig utilization levels will depend largely on the industry's management of this challenge.

High levels of activity will continue to exert cost pressure on the upstream industry. Escalating costs for drilling, operations, land and materials have all contributed to higher overall industry expenses. However, increases in gas prices have more than offset these higher costs and it is expected that this situation will continue for the projection period.

The increasing amount of drilling activity focused on NGC will drive a rapid increase in deliverability from that source. The remarkable growth expected in NGC deliverability is almost totally attributable to development of the coals of the Horseshoe Canyon, which is expected to peak over the next few years. The ongoing growth of NGC deliverability in the longer term depends on the success attained in commercial development of the very large NGC resources in the Mannville zone.

The increasing scale of NGC development has given rise to a number of public concerns such as aquifer protection, access to the resource and drilling footprint. The relatively low flow characteristics of NGC have raised concerns regarding the number of wells that could eventually be required to access the NGC resource. Drilling density is controlled through the issuance of holding permits by provincial regulatory agencies. Density issues might also be addressed through the practice of drilling several wells from a single location. The work of the CBM/NGC MAC initiated by the province of Alberta is attempting to address these and other concerns.

NGC is primarily methane and contains little to no natural gas liquids. A concern has been raised regarding the potential dilution impact on natural gas liquids recovery. This topic is more fully described in the Board's previous EMA *Short-term Outlook for Natural Gas and Natural Gas Liquids to 2006*.

The expected variability in deliverability from Nova Scotia's offshore will continue to present challenges to markets in the area over the projection period as consumers will need to adjust to supply fluctuations. Drilling activity in recent years in offshore Nova Scotia has not resulted in discoveries that warranted proceeding to development, and this lack of success has currently discouraged exploration activity. Over the longer term, LNG imports and other offshore gas resources may provide additional supplies to this region.

6.3 Conclusions

The Board expects annual average deliverability of conventional gas to decline slightly over the projection period, from 474 million m3/d (16.7 Bcf/d) in 2004 to 467 million m3/d (16.5 Bcf/d) in 2007. This small decrease is expected to be more than offset by growth in NGC deliverability from 4 million m3/d (0.1 Bcf/d) in 2004 to 25 million m3/d (0.9 Bcf/d) in 2007.

The deliverability outlook reflects the industry operating at practical maximum levels. Reinvestment in drilling capacity is robust with planned annual additions to the rig fleet more than 50 percent higher than typical years and at the limit of available shop capacity. Gas drilling is expected to rise by 20 percent over the period and will more likely be constrained by the size of the drilling fleet and available manpower than a shortage of investment. **Even with prices at current levels or higher, these constraints will likely keep Canadian gas drilling from rising faster than indicated.**

Initial productivity of new wells continues to decline and will require an increasing number of new wells each year just to hold deliverability constant. The decline in well productivity reflects the maturing of the WCSB. Although significant amounts of gas remain and companies have more drilling prospects than ever, gas is available in smaller increments and will require increasing levels of activity and effort for each added unit of deliverability.

NGC deliverability will more than compensate for declines from conventional gas sources over the period. The industry appears to have developed an understanding of the Horseshoe Canyon coals, and is beginning to scale up the development of this resource. **Over the long term, the flatter decline profile of NGC (and tighter gas) should help to slow overall basin declines somewhat.**

The province of Alberta and the industry are working at addressing drilling density, access to resources, noise, and other environmental aspects of the expected ramp-up in NGC activity. Avoiding negative impacts on aquifers and water supplies is a key public concern.

Sable deliverability is expected to jump by 20 percent in 2007 through the installation of offshore compression. This bump in production will push Sable production forward in advance of potential additional supplies from LNG and/or development of Deep Panuke.

GLOSSARY

Average connection	An average connection may apply to gas connections or NGC connections and represents the average producing characteristics of ALL connections (either gas or NGC) for a geographic area and connection year. Production data for the average connection for any grouping (geographic area/connection year) is calculated as: [total production for all connections in grouping, summed by normalized production month]/[the total number of connections in the grouping].
Canadian rig fleet	Drilling rigs that are listed in the Nickle's Energy Group weekly *Rig Locator Report*.
Connection	A completion in a geological horizon (or horizons) within a well for which oil and/or natural gas production is reported.
Connection year	The year associated with the "On Production Date" for a connection.
Conventional gas	Refers to natural gas from all sources other than NGC.
Decline rate	A term used to describe the decrease in production rate over time as a resource is depleted. There are various ways of expressing decline rates, and in this report **exponential decline** is the type used to define well production decline characteristics. With exponential decline, a straight line is exhibited when production rate is plotted against cumulative production, and the slope of the line defines the **nominal** decline rate (in this report it is expressed as fraction per year). Another way of expressing Decline Rate is in terms of effective decline rate, which is the decrease in production divided by the initial production rate. The effective decline rate can be converted into nominal terms using the equation: nominal decline rate = -ln(1 – effective decline rate)
Deep rig(s)	Drilling rigs with a depth capacity greater than 3050 m.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Depth capacity	The depth capacity (meters) for each drill rig as listed on the weekly *Rig Locator Report* published by Nickle's Energy Group
Drill day(s)	The number of days that a rig is engaged drilling a well, calculated as Drilling Completion Date minus the Spud Date plus 1.

Existing connections	Connections on production prior to January 1, 2005.
Future connections	Connections on production after January 1, 2005.
Gas connection	A connection for which natural gas production has been reported, and where that production is deemed to be conventional gas. If the connection has oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.
Gas well	A well bore with one or more geological horizons capable of producing natural gas.
Gas-intent drilling	Applies to drilling, drill days or wells deemed by the NEB to be undertaken for the purpose of exploiting conventional gas resources, excluding solution gas.
Marketable gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Medium rig(s)	Drilling rigs with a depth capacity greater than 1850 m and less then or equal to 3050 m.
NGC	Natural gas from coal
NGC connection	A connection for which natural gas production has been reported, and where that production is deemed to be NGC.
NGC-intent drilling	Applies to drilling, drill days or wells deemed by the NEB to be undertaken for the purpose of exploiting NGC resources.
Normalized production month	For any gas well connection and for any production month, the normalized production month is the number of months since the first month of production for the gas well connection.
Oil connection	A connection for which oil production has been reported, and where that production is deemed NOT to be associated with oil sands. If the connection has oil and gas production, the ratio of cumulative gas production to cumulative oil production is used to classify the connection as gas or oil.
Oil sands connection	A connection for which oil production has been reported, and where that production is deemed to be associated with oil sands.
Projection period	January 1, 2005 to December 31, 2007.
Rig categories	The groupings of Shallow, Medium and Deep drill rigs in the WCSB Rig Fleet, based on depth capacity.
Rig day(s)	Each day of the year for each drilling rig represents a rig day. The annual allocation of the rigs in the WCSB rig fleet to the various study areas results in an aggregate number of annual rig days for each area.
Rig utilization	In this EMA, rig utilization applies to drill rigs comprising the WCSB rig fleet and is calculated as Drill Days / Rig Days. Rig Utilization is determined separately for each rig category and study area in the WCSB as detailed in Appendix A.4.
Shallow rig(s)	Drilling rigs with a depth capacity less than or equal to 1850 m.

Solution gas	Natural gas that is produced from an oil well connection.
Study area(s)	The areas of the WCSB defined in Figure 2.2 of this EMA.
Target resource(s)	conventional oil, conventional gas, NGC, or oil sands. In this EMA, the drilling of each well is deemed to be for the purpose of exploiting one of the target resources.
WCSB rig fleet	Drilling rigs comprising the Canadian Rig Fleet that have been determined by the NEB to work predominantly in Alberta, B.C. and western Saskatchewan. This excludes drilling rigs of the Canadian Rig Fleet that are determined by the NEB to work predominantly in Eastern Saskatchewan, Eastern Canada (Offshore and Onshore) and Northern Canada (see Appendix A.1 for further details).

Appendices are available at http://www.neb-one.gc.ca/energy/EnergyReports/EMAGasSTDeliverabilityCanada2005_2007_e.htm

A. Analysis Regarding Determination of Number of Future Gas Connections

1. Components of Canadian Rig Fleet
Weekly location of rigs comprising each of the following rig groupings:

    a) WCSB rigs
    b) eastern Saskatchewan rigs
    c) northern Canada rigs
    d) east coast offshore rigs
    e) eastern Canada onshore rigs

2. WCSB Rig Fleet
Charts of historical and projected rig fleet growth by rig category for:

    a) shallow rigs
    b) medium rigs
    c) deep rigs
    d) All rigs

3. WCSB Rig Fleet
Allocation of rig days to study areas:

    a) Historical weekly rig count split to main geographic area (North, South and West)
        i. shallow rigs
        ii. medium rigs
        iii. deep rigs

    b) Tables of historical and projected annual rig day allocations to study areas:
        i. shallow rigs
        ii. medium rigs
        iii. deep rigs

4. Tables of Historical and Projected Rig Utilization
   a) shallow rigs
   b) medium rigs
   c) deep rigs

5. Tables of Historical and Projected Resource Targets for Drilling
   a) shallow rigs
   b) medium rigs
   c) deep rigs

6. Drill Days per Well for each Resource Target in each Study Area
   a) shallow rigs
   b) medium rigs
   c) deep rigs

7. Historical and Projected Drilling Levels for each Study Area for Gas-Intent and NGC-Intent Wells
   a) Table of drill days
   b) Table of wells

8. Ratio of Annual Connections to Annual Wells Drilled For Gas Directed and NGC Directed Wells for each Study Area

9. Fraction of Annual Gas Connections for each Month in Year by Study Area
   a) Conventional Gas Tables:
      Charts for each study area
   b) NGC Tables:
      Charts for AB-Southeast and AB-Central study areas

B. Analysis Regarding Production Performance

1. Group Performance Parameters for Existing Connections Applicable to Study Areas Comprising the WCSB:
   - Connection year groupings for all gas connections made before January 1, 2004
   - Connection year groupings for all NGC connections made before January 1, 2004
   - Solution gas deliverability Parameters

2. Historic and Projected Performance Parameters for Average Gas Well Connections and Average NGC Connections by Connection Year and Study Area

3. Trend of Initial Productivity of Average Gas Connection by Study Area
   - Appendices B.3.a thru B.3.l are charts showing initial productivity trend over time for each Study Area

4. Performance Charts (Rate versus Cumulative Production) for Historical and Projected Average Gas Connections for each Study Area
- Appendices B.4.a thru B.4.l are charts showing average gas connection production profiles for different connection years for each Study Area

C. Analysis Regarding Natural Gas from Coal (NGC)

1. Description of Process to create List of NGC Connections

2. Map of NGC Areas (Horseshoe Canyon and Mannville) and NGC Connections